ACCESSION #: 9603190015

LICENSEE EVENT REPORT (LER)

FACILITY NAME: ST LUCIE UNIT 2 PAGE: 1 OF 6

DOCKET NUMBER: 05000389

TITLE: Manual Reactor Trip Due to High Main Generator Cold Gas

Temperature

EVENT DATE: 01/05/96 LER #: 96-001-00 REPORT DATE: 01/24/96

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 035

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:

50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:

NAME: Edwin J. Benken, Licensing TELEPHONE: (407) 467-7156

Engineer

COMPONENT FAILURE DESCRIPTION:

CAUSE: X SYSTEM: TK COMPONENT: TC MANUFACTURER: F180

REPORTABLE NPRDS: Y

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On January 5, 1996, St. Lucie Unit 2 was operating at 35 percent power after returning to service following a refueling outage. After being placed in automatic, the main generator hydrogen cooler temperature control valve (TCV) failed to control properly, causing the temperature control valve to fully close. This valve regulates the flow of cooling water from the main generator hydrogen coolers. At 1636 the unit was manually tripped by utility licensed operators due to increasing main generator cold gas temperatures. All safety functions were satisfactorily met following the trip and the plant was stabilized in

Mode 3. Several unexpected Steam Generator (SG) low level indications were received following the trip and were subsequently found to be caused by partial sensing line blockage from accumulated corrosion products.

This event was caused by the failure of a hydrogen cooler temperature control valve controller to maintain the TCV in the proper position. Closure of the TCV caused a reduction in cooling water flow from the hydrogen coolers, resulting in increased cold gas temperatures in the main generator.

Corrective actions: 1)The TCV controller setting was adjusted prior to returning Unit 2 to service. 2) Additional controllers in other plant systems were inspected for proper operation. 3) Post maintenance testing of controllers is being reviewed for adequacy. 4) Operations is evaluating generic implications and will require additional oversight for this evolution in the future. 5) Controller setpoints will be reviewed for on into a data base. 6) Unit 2 SG level instrumentation sensing line blockage was cleared, and instrument performance was reviewed on Unit 1. 7) SG level sensing lines and others deemed susceptible will be blown down in the future as part of a preventative program. 8) Plant procedures wi be enhanced to facilitate early detection of instrument response abnormalities.

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DESCRIPTION OF THE EVENT

On January 5, 1996, St. Lucie Unit 2 was at approximately 35 percent power, as part of a power escalation program following a refueling outage. At approximately 1630 hours, a utility non-licensed operator closed the bypass valve around the temperature control valve (TCV-13-15) (EIIS:KB) for main generator hydrogen cooling. The bypass valve had previously been opened by operating shift personnel to aid in temperature control. Closure of the bypass placed the TCV in the fully automatic mode of operation. After locally checking the hydrogen cooler temperatures, the operator made an assessment that the system was functioning properly. Shortly after the bypass valve was closed, control room Annunciator D-59, "Generator Condition Monitor" (EIIS:IB) was received. Control Room licensed operators responded to the alarm and noted that main generator cold gas temperature was fluctuating.

A utility licensed operator was sent to locally assess the condition of the hydrogen cooler TCV. The operator observed that the TCV, which regulates cooling water flow from the main generator hydrogen coolers, was in the fully closed position. Several local adjustments were made in an attempt to restore normal operation of the valve, however these actions were not successful. At 1636, average hydrogen cold gas temperature had increased to 52 Degrees C, and in accordance with approved plant procedures, the reactor and turbine were manually tripped. The control room staff performed Standard Post Trip Actions, in accordance with Emergency Operating Procedure (EOP)-1, and all safety functions were met. Following the manual trip, several unexpected low Steam Generator (SG) level Reactor Protection System (RPS) (EIIS:JC) and Auxiliary Feedwater Actuation System (AFAS) (EIIS:BA) trip signals were received from both Steam Generators. Wide range SG level indications showed that actual SG water levels remained above the RPS trip setpoint of 20.5 percent narrow range level in both Steam Generators during this transient.

Following the completion of Standard Post Trip Actions the plant was stabilized in Mode 3 while awaiting the completion of a post-trip review.

CAUSE OF THE EVENT

The reactor was manually tripped by utility licensed operators in accordance with procedures to mitigate the effect of a loss of cooling water flow in the Main Generator Hydrogen Cooling System. The primary cause of this event was the failure of TCV-13-15 to automatically regulate cooling water flow from the main generator hydrogen coolers following local closure of the TCV bypass valve. A subsequent inspection showed that the valve controller derivative setting was incorrectly adjusted. Post maintenance testing performed after recent controller maintenance was insufficient to assure proper system operation. A contributing factor was the failure of Operations personnel to adequately monitor the evolution and ensure that system response was as expected following the local actions.

A cross functional team was assembled to investigate the cause of the low SG level trip signals which were received following the reactor trip.

The cause of the instrument behavior was found to be partial blockage of the SG level instrument sensing lines due to sludge accumulation. With the sensing lines partially blocked, a differential pressure developed across the blockage in the sensing line which resulted in a brief transient decrease in indicated Steam Generator level.

ANALYSIS OF THE EVENT

This event is reportable under 10CFR50.73 a.2.iv, as an event or condition which resulted in a manual or automatic actuation of any engineered safety feature, including the Reactor Protection System.

Utility licensed operators manually tripped the reactor and turbine in accordance with the Main Generator Off Normal Operating Procedure (ONOP) 2-2200030, due to increasing hydrogen gas temperature in the main generator to preclude equipment damage.

The plant response to this event is bounded by section 15.2.1.2 of the St. Lucie Unit 2 Updated Final Safety Analysis Report (UFSAR) which assumes a decreased heat removal by the secondary system due to isolation of the main turbine at 102 percent power. The actual plant response was more conservative than that described in the analysis for the following reasons: 1) The Unit was operating at reduced power (approximately 35 percent). 2) The reactor and turbine were manually tripped, and 3) Steam Generator pressure was maintained below the Main Steam Safety Valve (MSSV) (EIIS:SB) lift setpoints during the event. The capability of the steam generators to act as a primary heat sink was not affected by this event.

TCV 13-15 controller settings were adjusted prior to returning Unit 2 to service. Post maintenance testing of this controller and others is being assessed by plant staff to ensure that future testing adequately demonstrates controller operability. No damage occurred to the main generator as a result of the event.

The post-trip investigation of the observed SG level indications included a sensing line bleed test for each SG level detector. Various amounts of sludge were removed from the sensing lines for the narrow and wide range

SG level instrumentation, thus supporting the assumption that partial sensing line blockage was responsible for the observed indications. The cause of the sludge accumulation within the sensing lines was analyzed by plant Engineering, and determined to be the result of the gradual accumulation of corrosion products over a long time period. The mechanism for sludge transport into the sensing fine tubing is believed to be recirculation of sludge within the downcomer region, turbulence within the instrument connection bore, and the angle of the instrument connection. Once corrosion products entered the sensing line, they became trapped in the line, and because of greater density, worked their way to and accumulated within the lower elevations of the sensing line. The SG level instruments monitor level by comparing the differential pressure between a reference leg and a sensing leg. Both the reference and sensing legs are affected by steam generator pressure which, under normal conditions, is sensed equally on both sides of the detector. Only the sensing leg is affected by changes in actual SG level. The partial blockage of a sensing line effectively behaves as a restricting orifice. This results in a lag or time delay in the ability of the sensing line side of the instrument to sense actual pressure. The magnitude of the time delay is a function of the square root of the step change in pressure across the restriction; the greater the change in pressure, the greater the time delay. With partial blockage of the sensing line, any steam generator pressure transients result in the reference leg side of the detector responding to the pressure change instantaneously while the sensing leg side does not. Therefore, an increase in SG pressure will result in a false low level signal (as observed during the trip) and a decrease in SG pressure will result in a false high level signal. This indication will persist until pressure in the sensing line equalizes across the partial blockage.

ANALYSIS OF THE EVENT Continued

The time delay for liquid level transients is not as significant as for pressure transients since the change in pressure on the sensing leg is small. The SG level change associated with the trip represents a pressure decrease of approximately 1.25 psi. The pressure change associated with a SG water level change from 100 percent to 0 percent narrow range level is approximately 5 psi. In comparison, the observed SG pressure transient during the subject plant trip was approximately 55 psi. This transient was relatively brief, occurring over an 8 second period, compared to the greater time periods associated with SG level transients. It was concluded that the associated hydraulic pressure change due to the level change alone is therefore inconsequential with respect to the overall SG pressure transient.

Each Steam Generator has 4 narrow range level transmitter (LT) channels, (LT-9013 A thru D for 2A SG and LT-9023 A thru D for 2B SG). From the data collected following the trip, it was noted that not all channels of each Steam Generator's level transmitters were affected. Channels B and D of Steam Generator 2A (LT-9013B and LT-9013D) were not affected and thus would have provided a 2 out of 4 logic to trip the reactor and initiate auxiliary feedwater for any 2A and symmetrical SG transients. Channel A of Steam Generator 2B (LT-9023A) was not affected and Channel D (LT-9023D) was slightly affected for about 4 seconds, after which it tracked properly. The conclusion that Channels B and D of Steam Generator 2A and Channel A of Steam Generator 2B were not affected is based on their consistent and expected response to the symmetrical effects of the manual trip.

The safety function of the SG level instruments is identified in the Unit 2 UFSAR and Technical Specifications. Unit 2 Technical Specification 2.2.1 Bases describes the SG low level trip as providing protection against a loss of feedwater flow incident, protection against asymmetric steam generator events such as the opening of a Main Steam Safety Valve (MSSV) or Atmospheric Dump Valve (ADV), and allows for sufficient time to initiate auxiliary feedwater. UFSAR section 7.2.2.2.7 states that the low SG water level trip ensures sufficient time to actuate auxiliary feedwater for decay heat removal. Based on an Engineering disposition, the impact on the safety function associated with the SG level instrumentation is summarized below.

Inadvertent Opening of a MSSV or ADV

St. Lucie UFSAR section 15.1.3.1.1 discusses the inadvertent opening of a Steam Generator MSSV or ADV and notes that credit was taken for the protective action of the low SG level trip. Per Table 15.1.3-3, the trip occurs approximately 830 seconds into the event. UFSAR Figure 15.1.3-5 provides the SG pressure transient associated with this event. From this curve it is noted that there is an initial pressure fluctuation (drop then partial recovery) after which pressure stabilizes for about 600 seconds until the trip on low SG level. The SG level transient during this event is assumed to be linear and is estimated to be less than 0.1 percent level per second (based on an initial steady state level of 65 percent and level at trip of 5 percent). As discussed above, a level change will not result in a significant level mismatch between affected channels and properly operating channels. Because SG pressure is stable for 600 seconds prior to a trip signal which allows the affected transmitters' sensing lines to equalize pressure across any blockage, and because the water level transient is very slight, it is expected that the subject SG level instruments would have performed properly during this transient.

ANALYSIS OF THE EVENT Continued

Loss of Feedwater Flow

UFSAR appendix 10.4.9A describes a loss of feedwater event. Based on data presented in the UFSAR, the rate of change in SG level associated with a Loss of Feedwater (LOW event is less than that observed during the

Unit 2 plant trip. Therefore, the differential pressure developed across a sensing line restriction would be less for the LOFW event and the lag between an actual SG level change and the indicated level change would be less than that observed during the Unit 2 plant trip. As discussed previously, the magnitude of the error introduced by a liquid level transient is slight when compared to the error associated with a pressure transient. Since the effects of a pressure transient are dominant, and since a loss of feedwater event results in a SG pressure increase, it would be expected that any affected channels would initially respond with a false low level signal. If the error persisted, this false signal would result in earlier than normal AFAS actuation or RIPS trip.

Channels B and D of Steam Generator 2A (level transmitters LT-9013B and LT-9013D) were operable and capable of providing proper reactor trip and auxiliary feedwater signals for all symmetrical SG feedwater events and any Steam Generator 2A level events. Additionally, as observed on the data for Steam Generator 2B, channel A was operable and channel D, although slightly affected for about 4 seconds, tracked properly below a SG level of about 55 percent (well above RPS and auxiliary feedwater set points) and thus would have provided proper reactor trip and auxiliary feedwater signals if required.

Based on the above, there is no past operability concern associated with the subject S/G level transmitters for a loss of feedwater flow event or for an event involving the inadvertent opening of a MSSV or ADV.

All plant safety functions were satisfactorily met during this event, and the health and safety of the public were not adversely affected by the event.

CORRECTIVE ACTIONS

1) The hydrogen cooler TCV controller (TCV 13-15) settings were adjusted by Instrument and Control technicians prior to returning Unit 2 to service.

2) Additional plant secondary system controllers were inspected by plant maintenance and operations personnel to check proper operation. No additional problems were found.

3) The plant Operations Support and Testing (OST) group is reviewing the post-maintenance testing of this and other selected system controllers to determine if the testing adequately demonstrates proper controller operation.

4) Operation of the hydrogen cooler TCV will be included into a current list of sensitive evolutions which require additional Operations oversight.

CORRECTIVE ACTIONS Continued

5) Operations will evaluate this event for generic implications to include communications, self-verification, and plant response. Special attention will be given to evolutions which involve placing process controllers into or out of the automatic mode of operation.

6) Recommended controller settings will be evaluated for inclusion into the Total Equipment Data Base (TEDB) to be referenced when performing maintenance.

7) The narrow and wide range Steam Generator level instrumentation sensing lines on Unit 2 were blown down to remove any existing blockage.

8) A review of post trip data from previous plant trips on Unit 1 was performed to determine if SG level instruments had been affected on that Unit. This review did not indicate a similar problem with the Unit 1 instruments.

9) As part of a continuing preventative maintenance program, SG level sensing lines on both Units 1 and 2 will be blown down during refueling outages.

10) Additional instrumentation sensing lines in selected systems will be tested for blockage on both Units 1 and 2 during the next outage of sufficient duration. The results of this testing will be used to enhance the preventative maintenance program for those instruments in systems deemed to be susceptible to this problem.

11) Operating Procedure OP 0030119, "Post Trip Review," will be revised to include additional guidance to enhance the early identification of instrumentation discrepancies and verify proper sequence of event response.

12) An entry has been made on the INPO Nuclear Network to notify other

utilities of this event.

ADDITIONAL INFORMATION

Failed Component Identification

Manufacturer: Foxboro

Model Number: 43AP-FA52C

Device: Temperature Control Valve Controller

Previous Similar Occurrences

LER 389-93-008 "Manual Reactor Trip Due to High Gas Temperature in

the Main Generator Caused by a Procedural

Deficiency". This event describes a unit trip due to

high main generator gas temperatures due to the

improper operation of the Turbine Cooling Water

System. The event was attributed to insufficient

procedural guidance.

ATTACHMENT 1 TO 9603190015 PAGE 1 OF 1ATTACHMENT 1 TO 9603190015 PAGE 1 OF 1

Florida Power & Light Company, P.O. Box 128, Fort Pierce, FL 34954-0128

January 24, 1996

FPL RESUBMITTAL 3-12-96

L-96-14

10 CFR 50.73

U. S. Nuclear Regulatory Commission

Attn: Document Control Desk

Washington, D. C. 20555

Re: St. Lucie Unit 2

Docket No. 50-389

Reportable Event: 96-001

Date of Event: January 5, 1996

Manual Reactor Trip Due to High Main Generator

Cold Gas Temperature

The attached Licensee Event Report is being submitted pursuant to the requirements of 10 CFR 50.73 to provide notification of the subject event.

Very truly yours,

D. A. Sager

Vice President

St. Lucie Plant

DAS/EJB

Attachment

cc: Stewart D. Ebneter, Regional Administrator, USNRC Region II

Senior Resident Inspector, USNRC, St. Lucie Plant

an FPL Group company

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